Raquel Webster
Senior Counsel

December 19, 2018

BY HAND DELIVERY AND ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4755 – 2018 Energy Efficiency Program Plan
Responses to Division Data Requests – Set 10

Dear Ms. Massaro:

I have enclosed ten copies of National Grid's[1] responses to the Division's Tenth Set of Data Requests in the above-referenced docket.

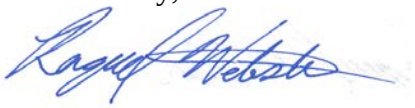
This filing also contains a Motion for Protective Treatment of Confidential Information in accordance with Rule 1.2(g) of the Public Utilities Commission's (PUC) Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). National Grid seeks protection from public disclosure of certain confidential and privileged information, which is contained in Attachment DIV 10-29. In compliance with Rule 1.2(g), National Grid has provided the PUC with one complete, unredacted copy of the confidential version of Attachment DIV 10-29 in a sealed envelope marked **"Contains Privileged and Confidential Materials – Do Not Release."**

The Company is also enclosing a USB Flash Drive containing an Excel version of Attachment DIV 10-8-2.

Please be advised that the following responses in this set remain pending: Division 10-21, Division 10-25, and Division 10-30.

Thank you for your attention to this filing. If you have any questions, please contact me at 781-907-2121.

Sincerely,



Raquel J. Webster

Enclosures

cc: Docket 4755 Service List
Jon Hagopian, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

_____ December 19, 2018

Raquel J. Webster, Esq. Date

Docket No. 4755 - National Grid – Energy Efficiency Program Plan for 2018
Docket No. 4756 - National Grid – 2018 System Reliability Procurement Report (SRP)
Service list updated 10/24/18

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
BEFORE THE PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID – ELECTRIC AND GAS DISTRIBUTION RATE FILING	)	Docket No. 4755

THE COMPANY'S MOTION
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

The Company[1] respectfully requests that the Rhode Island Public Utilities Commission (PUC) provide confidential treatment and grant protection from public disclosure of certain confidential and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I. Gen. Laws. § 38-2-2(4)(B). The Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to Rule 1.2(g)(2).

I. BACKGROUND

On December 19, 2018, the Company filed responses to the Rhode Island Division of Public Utilities and Carriers' (the Division) Tenth Set of Data Requests in Docket 4755 dated November 27, 2018 (Division Set 10). Division Set 10 included: (a) Data Request Division 10-29, which sought an annual gas distribution and supply bill estimate for the CHP unit based on current rates.

The Company's response to Data Request Division 10-29 includes Attachment DIV 10-29 Confidential, which contains the Navy's usage data. This information is confidential and proprietary. The Company seeks confidential treatment of Attachment DIV 10-29 in its entirety.

[1] The Narragansett Electric Company d/b/a National Grid (the Company).

II. LEGAL STANDARD

PUC Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* Under the APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). Therefore, to the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of the APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would be likely either to (1) impair the Government's ability to obtain necessary information in the future; or (2) cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I. 2001). Disclosure of information would impair the Government's ability to obtain such information in the future when: (a) information is provided voluntarily to the governmental agency, and (b) that information is of a kind that customarily would not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

III. BASIS FOR CONFIDENTIALITY

The information contained in Attachment DIV 10-29 Confidential falls within the exceptions under the APRA. Specifically, the attachment contains data about customer usage and historical gas consumption. The Company does not and should not reveal this confidential information about its customers, and the Company ordinarily would not share this information with the public.

The Company, therefore, is providing Attachment DIV 10-29 Confidential to the PUC on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to these attachments.

IV. CONCLUSION

Accordingly, the Company respectfully requests that the PUC grant protective treatment to Attachment DIV 10-29 Confidential.

WHEREFORE, the Company respectfully requests that the PUC grant this Motion for Protective Treatment.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY

By its attorney,

Raquel J. Webster, RI Bar # 9064
National Grid
40 Sylvan Road
Waltham, MA 02451
781-907-2121

Dated: December 19, 2018

Division 10-1

Request:

Please provide up-to-date estimates of electricity production and fossil fuel consumption from (i) the CHP Project and (ii) the Navy's pre-existing central boiler plant that would still be utilized and on stand-by after the proposed CHP unit becomes fully operational, including the following:

(a) Total annual hours of operation of the CHP unit;
(b) Total annual MMBtu's of natural gas to be consumed, in the aggregate, at the CHP unit and the central boiler plant post-CHP;
(c) Total annual MMBtu's of natural gas consumed at the CHP unit alone;
(d) Total annual MMBtu's of natural gas consumed at the central boiler plant alone, post-CHP project;
(e) Total increase in MMBtu's of natural gas consumed in the aggregate post-CHP, compared to natural gas consumption prior to the CHP project being built;
(f) Total annual MMBtu's of oil consumed that would continue to be used at the central boiler plant (please identify #2 and #4 oil separately), post-CHP project;
(g) Total annual net decrease in MMBtu's of oil being consumed at the central boiler plant post-CHP, compared to oil consumption prior to the CHP project being built (please identify #2 and #4 oil separately);
(h) Total annual gross kWh of electricity that will be produced by the CHP unit;
(i) Total annual net kWh of electricity that will be produced by the CHP unit (net of parasitic load);
(j) Total annual kWh electricity savings from the CHP project as would be reported for the energy efficiency program, based on all the assumptions provided in this response;
(k) Assumed gross electric generating capacity of the CHP unit;
(l) Assumed net electric generating capacity of the CHP unit (net of parasitic load); and
(m) The historical annual baseline fossil fuel consumption at the Navy's central boiler plant used for determining the change in MMBtu usage as a result of the CHP unit being built, broken down by total MMBtu's of natural gas consumed and total annual MMBtu's of oil consumed pre-CHP (identifying #2 and #4 oil separately).

Response:

During the technical assessment of the Navy CHP project, The Narragansett Electric Company d/b/a National Grid (the Company) reviewed an energy model provided by BQ subcontractor Greg Hester of Efficiency by Design (EBD) with his involvement and assistance. The energy

Division 10-1, page 2

model is based on the Navy's historic hourly electric and steam loads, and gas and oil consumption using 2015 as the modeled year. The Company's engineers then adjusted some model inputs based on the Company's experience with other CHP systems, resulting in more conservative estimated savings values. The Company described the model revisions it made in January 2018 in its response to data request Division 10-16, and additional model revisions from August 2018, which corrected for interruptible gas supply at the central steam plant, are described between pages 1653 to 1726 of the public version of Attachment DIV 4-1. The Company completed a revised model on August 5, 2018, and the following current values come from that revised model:

(a) Total annual hours of operation of the CHP unit: 4,532 hours/year;

(b) Total annual MMBtu's of natural gas to be consumed, in the aggregate, at the CHP unit and the central boiler plant post-CHP: 465,591 MMBtu/year;

(c) Total annual MMBtu's of natural gas consumed at the CHP unit alone: 440,283 MMBtu/year;

(d) Total annual MMBtu's of natural gas consumed at the central boiler plant alone, post-CHP project: 25,308 MMBtu/year;

(e) Total increase in MMBtu's of natural gas consumed in the aggregate post-CHP, compared to natural gas consumption prior to the CHP project being built: 301,675 MMBtu/year;

(f) Total annual MMBtu's of oil consumed that would continue to be used at the central boiler plant (please identify #2 and #4 oil separately), post-CHP project: #4 oil - 11,730 MMBtu/year; #2 oil - 2,932 MMBtu/year;

(g) Total annual net decrease in MMBtu's of oil being consumed at the central boiler plant post-CHP, compared to oil consumption prior to the CHP project being built (please identify #2 and #4 oil separately): #4 oil - 21,594 MMBtu/year; #2 oil - 5,399 MMBtu/year;

(h) Total annual gross kWh of electricity that will be produced by the CHP unit: 37,120,919 kWh/year;

Division 10-1, page 3

(i) Total annual net kWh of electricity that will be produced by the CHP unit (net of parasitic load): 36,155,757 kWh/year;

(j) Total annual kWh electricity savings from the CHP project as would be reported for the energy efficiency program, based on all the assumptions provided in this response: 36,155,757 kWh/year;

(k) Assumed gross electric generating capacity of the CHP unit: Gross electric generating capacity of a gas turbine driven generator varies as a function of incoming air temperature. In the energy model, the gross generator output varies between 7.1 and 9.0 gross MW. The relationship between incoming air temperature and generating capacity can be seen in the MRD document, Milestone 2a, section 3e.

(l) Assumed net electric generating capacity of the CHP unit (net of parasitic load): The net generating capacity of a gas turbine driven generator varies as a function of incoming air temperature. The energy model estimated a constant parasitic load of 213 kW, which was subtracted from the hourly estimate of gross generating capacity for each hour of the modeled year when the generator was operating, resulting in a range of 6.9 to 8.8 net MW.

(m) The historical annual baseline fossil fuel consumption at the Navy's central boiler plant used for determining the change in MMBtu usage as a result of the CHP unit being built, broken down by total MMBtu's of natural gas consumed and total annual MMBtu's of oil consumed pre-CHP (identifying #2 and #4 oil separately): The original energy model resolved the fuel consumption into MMBtus for the annual hourly energy modeling, and split out the gas/oil fuel mixture in summary values based on the Navy's utility purchases for 2015, which were 62% gas/38% oil, where the oil breakdown was 95% #4 oil + 5% #2 oil. Company engineers updated the gas/oil split to more recent 2017 consumption values, which resulted in a 80% gas/20% oil split, where the oil breakdown was 80% #4 oil and 20% #2 oil. This adjustment resulted in a baseline boiler fuel utilization estimate of:

Central Plant Boiler Fuel Consumption Baseline Estimate

	MMBtu/yr
Natural gas	163,917
#4 oil	33,325
#2 oil	8,331
Total	205,572

Prepared by or under the supervision of: Mark DiPetrillo

Division 10-2

Request:

Please provide the information requested in request 10-1 (a), (b), (c), (d), (f), (h), (i), and (j) above on a monthly basis, corresponding to the same annual estimates given in the response. (NOTE: If it is not practicable to identify type of oil usage monthly for (f), the total monthly MMBtu's of oil consumption is sufficient)

Response:

Please see the table below for the requested information.

	(a)	(b)	(c)	(d)	(f)	(h)	(i)
Row Label	**Sum of Hours Counter for Turbine**	**Sum of CHP system + Boiler gas (MMBTU)**	**Sum of CHP system gas (MMBTU)**	**Sum of Post CHP Boiler gas (MMBTU)**	**Sum of Post CHP Boiler oil (MMBTU)**	**Sum of Gross Turbine Output (kWh)**	**Sum of Net Turbine Output (kWh)**
Jan	599	69,476	61,748	7,728	5,791	5,119,754	4,992,188
Feb	672	72,950	71,227	1,724	8,061	5,828,452	5,685,339
Mar	599	70,927	60,506	10,422	811	5,033,747	4,906,180
Apr	720	67,741	67,606	135	-	5,792,126	5,638,790
May	216	19,656	19,656	0	-	1,680,459	1,634,458
Jun	0	-	-	-	-	-	-
Jul	0	-	-	-	-	-	-
Aug	0	-	-	-	-	-	-
Sep	0	-	-	-	-	-	-
Oct	407	37,560	37,263	297	-	3,191,020	3,104,343
Nov	575	57,888	53,121	4,767	-	4,554,469	4,432,013
Dec	744	69,392	69,155	237	-	5,920,892	5,762,445
Grand Total	**4532**	**465,591**	**440,283**	**25,308**	**14,662**	**37,120,919**	**36,155,757**

Sub-part (j) values are exactly the same as the values in sub-part (i).

Prepared by or under the supervision of: Mark DiPetrillo

Division 10-3

Request:

Please provide a reference to the source of the information used to provide the estimates given in response to request 10-1 above, and an explanation of how each estimate was determined. If the estimate is the result of a calculation, please provide the calculation.

Response:

As described in The Narragansett Electric Company d/b/a National Grid's (the Company) response to data request Division 10-1, the energy values were calculated using an annual hourly energy model, which used the customer's historic electric and steam load information, expected CHP and central plant operating sequences, and expected CHP system performance from manufacturer specification sheets to estimate future energy consumption and savings.

The energy model was provided by Efficiency by Design (EBD) and reviewed by Company engineers with adjustments to some model inputs under a Non-Disclosure Agreement (NDA). In compliance with the NDA, the Company has conferred with EBD regarding sharing its proprietary model, and EBD has declined to grant the Company authority to provide copies of the model. EBD has offered to arrange for an *in camera* review of the model with the Rhode Island Division of Public Utilities and Carriers.

Prepared by or under the supervision of: Mark DiPetrillo

Division 10-4

Request:

Please explain how the Company has estimated what the fuel consumption is likely to be at the central boiler plant post-CHP, including identification of the key assumptions and workpapers showing how the fuel split was derived and calculated.

Response:

The annual hourly energy model provided by Efficiency by Design (EBD) and reviewed by The Narragansett Electric Company d/b/a National Grid (the Company) contains the key assumptions and is the workpaper for this project. Please see the Company's response to data request Division 10-3 regarding the Company's ability to share the EBD model with the Division.

The Company used the EBD model to calculate the CHP system (heat recovery steam generator plus duct burner) steam output in relation to historic steam loads, with the central boiler plant providing back-up and peak steam needs during planned or unplanned outages of the CHP system, including temperature dependent gas service interruptions where the central plant boilers are expected to use oil. The CHP system is expected to be the "first run, large boiler" steam provider for the Navy's steam distribution system, which displaces a majority of the historic fuel consumption of the central plant boilers. The below chart shows historic consumption and estimated fuel usage values for the central plant and CHP system.

Navy Building 7CC Fuel Summary	Gas MMBtu/yr	#4 Oil MMBtu/yr	#2 Oil MMBtu/yr	Total MMBtu/yr	Gas %	#4 Oil %	#2 Oil %
2014 Boilers	136,736	77,332	9,694	223,762	61%	35%	4%
2015 Boilers	127,771	75,311	4,196	207,277	62%	36%	2%
2016 Boilers	151,537	41,561	1,695	194,792	78%	21%	1%
2017 Boilers	164,787	34,264	7,613	206,664	80%	17%	4%
Forecast:							
CHP System	440,283			440,283	100%		
Central plant Boilers	25,308	11,730	2,932	39,970	63%	29%	7%

62% gas / 38% oil proportion from original EBD model
80% gas / 20% oil proportion for 2017, Jan 2018 calculation
63% gas / 37% oil Aug 2018 temperature curtailment proportion

Prepared by or under the supervision of: Mark DiPetrillo

Division 10-5

Request:

Please provide the fossil fuel consumption at the Navy's central boiler plant for calendar years 2013, 2014, 2015, 2016, and 2017, broken down as follows:

(a) Total annual MMBtu's of natural gas consumed;
(b) Total annual MMBtu's of oil consumed (please identify #2 and #4 oil separately)
(c) Average cost per MMBTU for oil (by #2 and #4 separately, if available); and
(d) Average cost per MMBTU for gas.

Response:

Please see the table below for the response to this data request. The letters in the table are direct responses to subparts (a) through (d) above.

Navy Building 7CC Central Plant Fuel Summary

YEAR	(a)	(b)		(c)		(d)
	Gas MMBt	#4 MMBtu/yr	#2 MMBtu/yr	#4 $/MMBtu	#2 $/MMBtu	Gas $/MMBtu
2013	188,869	27,723	*	$ 16.17	$ 23.20	$7.13
2014	136,736	77,332	9,694	$ 15.74	$ 22.45	$ 8.65
2015	127,771	75,311	4,196	$ 14.77	$ 20.22	$ 7.00
2016	151,537	41,561	1,695	$ 12.80	$ 18.42	$ 4.92
2017	164,787	34,264	7,613	$ 12.71	$ 14.14	$ 7.01

Data was included in the original EBD energy model
Data was supplied by US navy on 12-17-18

* On 12-17-18 the US Navy indicated that their total #2 oil consumption in 2013 was 94,038 Gals.
(12,977MMBtu) The Navy believe that 60% of that goes to 7CC. The rest goes to Bldg. 292 & Bldg 68 Pier 2

Prepared by or under the supervision of: Mark DiPetrillo

Division 10-6

Request:

In order to facilitate a comparison of the inputs between (i) the corrected BCR calculation of August 5, 2018 and (ii) the original calculation in January 2018, please provide the electricity production and fossil fuel consumption estimates for the CHP Project and the Navy's pre-existing central boiler plant that would still be utilized and on stand-by after the proposed CHP unit becomes fully operational, which estimates were used by the Company when performing the BCR calculation around the time of making the first incentive offer in January 2018 (as reflected in the original response to Division 1-3), including all the same type of information requested in requests 10-1 and 10-2 above.

Response:

The primary reason for the difference between January 2018 and the August 5, 2018 BCR calculation values is recalculation of the energy impacts due to temperature dependent gas service interruptions at the central boiler plant, which increased oil usage. Secondarily, Efficiency by Design recommended a higher "heat rate safety factor" when asked to review the energy model revisions in August 2018.

Please see Attachment DIV 10-6 for a table showing a line-to-line comparison of values.

10-1 subpart	Label	Unit	Jan 2018 value	August 2018 revision	Notes:
(a)	Operating hours	hours/year	4,532	4,532	
(b)	CHP + Boiler gas consumed	MMBtu/yr	463,957	465,591	Due to increased oil use + heat rate safety factor adjustment
(c)	CHP + duct burner gas consumed	MMBtu/yr	432,085	440,283	Due to 2% increase in gas turbine 'heat rate safety factor'
(d)	Boiler gas consumed	MMBtu/yr	31,871	25,308	Reduced gas use due to increase in gas curtailment
(e)	Total Incremental gas consumed	MMBtu/yr	300,040	301,675	Due to increased oil use + heat rate safety factor adjustment
(f)	Total boiler #4 oil consumed	MMBtu/yr	6,480	11,730	Increased oil consumption due to gas curtailment
	Total boiler #2 oil consumed	MMBtu/yr	1,620	2,932	Increased oil consumption due to gas curtailment
(g)	Total boiler #4 oil saved	MMBtu/yr	26,845	21,594	Increased oil consumption due to gas curtailment
	Total boiler #2 oil saved	MMBtu/yr	6,177	5,399	Increased oil consumption due to gas curtailment
(h)	Total gross electricity generation	kWh/yr	37,120,919	37,120,919	
(i)	Total net electricity generation	kWh/yr	36,155,757	36,155,757	
(j)	Total estimated savings claim	kWh/yr	36,155,757	36,155,757	
					Summary Values used in BCR calculation

Division 10-7

Request:

If different from the information provided in response to requests 10-1 and 10-2 above, please provide the electricity production and fossil fuel consumption estimates for the CHP Project and the Navy's pre-existing central boiler plant that would still be utilized and on stand-by after the proposed CHP unit becomes fully operational, which estimates were used by the Company when performing the corrected BCR calculation filed on August 5, 2018 (corrected Division 1-3), including the same type of information requested in 10-1 and 10-2 above.

Response:

The electricity production and fossil fuel consumption estimates for the CHP Project and the Navy's pre-existing central boiler plant that would still be utilized and on stand-by after the proposed CHP unit becomes fully operational, are the same as the information provided in The Narragansett Electric Company d/b/a National Grid's responses to data requests Division 10-1 and Division 10-2. The Company used these estimates when it performed the corrected BCR calculation, which the Company submitted to the Division on August 5, 2018.

Division 10-8

Request:

Referring to the avoided cost tables used in the calculation of the BCR provided in corrected Division 1-3:

(a) Are the avoided cost tables used in the calculation of the BCR derived from the original AESC 2015 Study or the AESC 2015 Update?

(b) If the new AESC 2018 Study released in March of 2018 and finalized in October of 2018 were used to derive the avoided cost values in the tables of corrected Attachment Division 1-3, what impact would using the updated avoided cost figures from the AESC 2018 Study have on the BCR result, as calculated in corrected Attachment Division 1-3?

(c) Please provide a re-calculation of the BCR provided in corrected Division 1-3 using the avoided cost values from the AESC 2018 Study in place of the avoided cost values used in the calculation contained in corrected Attachment Division 1-3, and provide a copy of the excel file used in the calculation.

Response:

(a) The AESC 2015 Study Update was used for the January and August BCR calculations and is the same data used for screening required by the 2018 Rhode Island Energy Efficiency plan.

(b) If the new AESC 2018 Study released in March of 2018 and finalized in October of 2018 is used to derive the avoided cost values, then the BCR result increases to 1.61.

(c) Please see the table provided in Attachment DIV 10-8-1 and the Excel file used for the calculation provided in Attachment DIV 10-8-2. In the absence of an avoided cost value for commercial #2 oil in the 2018 AESC Study, The Narragansett Electric Company d/b/a National Grid contacted Synapse Energy Economics, Inc., the study authors, to confirm that using the lower avoided cost value for #4 oil is a conservative estimate of the value of #2 oil, with respect to the BCR calculation.

Using 2018 AESC values

	Economic Benefit	Electric kWh benefits		CO2 benefits		Oil Benefits		Negative benefits	
Total kWh saved	One-time $/project cost	Winter On-Peak kWH	Winter Off-Peak kWh	Winter On-Peak Energy CO2 Costs	Winter Off-Peak Energy CO2 Costs	#4 oil savings MMBtu/yr	#2 oil savings MMBtu/yr	Gas savings Heat MMBTU	O&M $/yr
36,155,757	$ 17,500,000	17,193,413	18,962,345	17,193,413	18,962,345	21,594	5,399	(301,675)	(687,500)
Electric line loss: 8%		18,568,886	20,479,332	18,568,886	20,479,332				
From AESC 2018 table:									
Energy		$ 1.29	$ 1.17			$ 386.34	$ 386.34	$ 167.19	
DRIPE		$ 0.62	$ 0.44					$ 0.18	
Cross DRIPE		$ 0.01	$ 0.01					$ 3.06	
CO2				$ 0.79	$ 0.81	$ 156.70	$ 156.70	$ 113.87	
NOx		$ 0.03	$ 0.03			$ 19.85	$ 19.85	$ 11.48	
Total Unit dollar value (using 20 yr meas. life)	$ 0.80	$ 1.95	$ 1.65	$ 0.79	$ 0.81	$ 562.89	$ 562.89	$ 295.80	$ 19.110
Reference for Dollar Values	Docket 4755, Attach 4, Bates page 12	2018 AESC sum of values	2018 AESC sum of values	2018 AESC sum of values	2018 AESC sum of values	2018 AESC sum of values	2018 AESC sum of values	2018 AESC sum of values	2018 Avoided Cost Tab (cell AT61)
Lifetime Total $ Values	$ 14,000,000	$ 36,195,256	$ 33,877,085	$ 14,731,229	$ 16,593,096	$ 12,155,207	$ 3,038,802	$ (89,234,125)	$ (13,137,812)

Navy CHP 2018 AESC RI Test B/C Ratio

	Project cost -->	$ 17,500,000
Economic $ benefits	$ 14,000,000	
Electric $ benefits	$ 101,396,666	
Oil $ benefits	$ 15,194,008	
Gas $ benefits	$ (89,234,125)	
O&M $ benefits	$ (13,137,812)	
	Total benefits -->	$ 28,218,738
	Total B/C ratio -->	1.61

#4 benefits used in the absence of commercial #2 oil value in AESC 2018 Study; #4 benefits are lower than #2, so this represents a conservative estimate.

Attachment DIV 10-8-2

Please see the Excel version of Attachment DIV 10-8-2 on a USB Flash Drive

Prepared by or under the supervision of: Rachel Henschel

Division 10-9

Request:

The Commercial Services/Main Agreement signed on May 4, 2018 by BQ Energy represents that the total MMBtu consumption from the CHP Unit would be 533,371 dekatherms, as stated in the table on the first page of the Agreement. (see pages 1117 through 1121 of Attachment DIV 4-1) Based on other information provided in the data responses in this case, that consumption figure appears to be significantly higher than other annual MMBtu estimates for the CHP unit that were used by the Company for other purposes. If the estimate of 533,371 was different than other estimates or otherwise outdated on the date of signing, why did the Company accept it in the definitive service agreement that was executed in May of 2018?

Response:

In July 2017, the Lead Account Manager – Customer Gas Connections used an estimated annual consumption for the CHP equipment of 533,371 dekatherms for Contribution in aid of Construction (CIAC) calculation purposes before The Narragansett Electric Company d/b/a National Grid (the Company) received specific energy model information from BQ Energy LLC (BQ). After the Company received the energy model information from BQ, the estimated annual gas consumption of the CHP equipment changed, but the Lead Account Manager – Customer Gas Connections was unaware of the changes. Therefore, the original estimated annual consumption was not updated and was used on the service agreement that was executed in May of 2018. The revised estimated annual consumption of 440,283 dekatherms has been included on the latest draft Commercial Gas Service/Main Agreement which was sent to the Navy on November 30, 2018.

Division 10-10

Request:

The CIAC calculation provided in response to Division 6-3 uses an estimate of 533,731 dekatherms to calculate the "New Delivery Revenues" for purposes of determining whether there are enough incremental revenues from the project to avoid a customer contribution for the gas distribution system reinforcements. In contrast, the estimate for incremental MMBtu's of new gas consumption from the CHP unit used in the BCR calculation is approximately 300,000 MMBtus. Please explain why the CIAC calculation used 533,731dekatherms as an estimate of incremental gas usage, while the BCR used only 300,000 MMBtus. Please also explain why the two estimates for incremental MMBTu's/dekatherms of gas should not have been the same and why the estimates were different.

Response:

In July 2017, the estimated annual gas consumption for the CHP equipment was 533,731 dekatherms. The Narragansett Electric Company d/b/a National Grid (the Company) used this estimate and associated distribution revenues to develop the Contribution in Aid of Construction (CIAC) calculation provided in the Company's response to data request Division 6-3. Please see the Company's response to data request Division 10-9.

As explained in the Company's response to data request Division 9-14, in the original CIAC analysis (Attachment DIV 6-3-2), the Company used only the estimated gas consumption of the CHP equipment to determine the relevant incremental firm distribution revenues because the ratemaking treatment of the non-firm central steam plant revenues precluded a reduction in revenues associated with a decrease in consumption. At that time (July 2017), the Company did not retain any non-firm revenues above the amount imputed into base distribution rates. All revenues associated with marginal non-firm gas volumes were returned to firm customers, and the Company was allowed to reconcile non-firm revenues to the amount imputed into base distribution rates through the On-System Margin credit factor. Therefore, the reduction in non-firm gas volumes at the central steam plant and the associated distribution revenues were excluded from the original CIAC analysis.

As further explained in the Company's response to data request Division 9-14, on August 30, 2018, the Rhode Island Public Utilities Commission (PUC) issued Order No. 23265 in Docket No. 4708, which changed the ratemaking treatment of non-firm revenues effective November 1, 2017 such that the Company now retains 100% of any marginal non-firm revenues. Because the Navy's existing central boiler plant receives non-firm service on Rate 61, and because operation of the proposed CHP equipment will reduce gas consumption at the central boiler plant, the

Division 10-10, page 2

revised CIAC calculation now must account for the associated reduction in non-firm revenues now retained by the Company. This revised CIAC calculation was provided as Attachment DIV 9-14-4 and uses an incremental net gas consumption of 301,675 dekatherms (as the same consumption value used in the BCR). This figure differs from the original annual gas consumption estimate of 533,731 dekatherms because:

a.) the estimated annual gas consumption of the CHP equipment had been changed from 533,731 dekatherms to 440,283 dekatherms; and
b.) the reduction in non-firm central steam plant gas consumption of 138,608 dekatherms was now subtracted from the incremental CHP equipment consumption.

Please also see Attachment DIV 9-14-3 for a calculation of the incremental gas consumption associated with the CHP project.

Division 10-11

Request:

Please provide the following information used for the CIAC calculation that was performed in July of 2017 for purposes of determining "New Delivery Revenue" that would offset the cost of the gas distribution system reinforcement project (Division 6-3):

(a) Total annual hours of operation of the CHP unit;
(b) Total annual MMBtu's of natural gas consumed, in the aggregate, at the CHP unit and the central boiler plant;
(c) Total annual MMBtu's of natural gas consumed at the CHP unit alone;
(d) Total annual MMBtu's of natural gas consumed at the central boiler plant alone;
(e) Total increase in MMBtu's of natural gas consumed, compared to natural gas consumption prior to the CHP project being built;
(f) Total annual increase in MMBtu's assumed in the CIAC calculation for purposes of measuring incremental revenue from the CHP project.

Response:

Please refer to the following information used for the CIAC calculation that was performed in July of 2017:

(a) The total annual hours of operation of the CHP unit: 5,832;

(b) The total annual MMBtu's of natural gas consumed, in the aggregate, at the CHP unit and the central boiler plant: 536,187;

(c) The total annual MMBtu's of natural gas consumed at the CHP unit alone: 533,731;

(d) The total annual MMBtu's of natural gas consumed at the central boiler plant alone: 2,456. The central boiler plant consumption was not used in the CIAC calculation. Please see The Narragansett Electric Company d/b/a National Grid's (the Company) response to data request Division 10-10;

(e) Total increase in MMBtu of natural gas consumed, compared to natural gas consumption prior to the CHP project being built: 372,270 (equal to 536,187 MMBtu from part (b) above minus 163,917 MMBtu's gas consumption prior to the CHP project being built).

Division 10-11, page 2

(f) Total annual increase in MMBtu's assumed in the CIAC calculation for purposes of measuring incremental revenue from the CHP project: 533,731 from part (c) above. Please see the Company's response to data request Division 10-10.

Division 10-12

Request:

For purposes of facilitating a comparison of inputs, please provide the same type of information requested in 10-9 above that corresponds to the revised CIAC calculations provided in response to Division 9-14.

Response:

The Narragansett Electric Company d/b/a National Grid (the Company) conferred with the Rhode Island Division of Public Utilities and Carriers (the Division) and clarified that the Division intended to refer to data request Division 10-11 rather than data request Division 10-9.

Please refer to the following information, which is the same type of information provided in the Company's response to data request Division 10-11 that corresponds to the revised Contribution in Aid of Construction (CIAC) calculations provided in the Company's response to data request Division 9-14:

(a) The total annual hours of operation of the CHP unit: 4532;

(b) The total annual MMBtu's of natural gas consumed, in the aggregate, at the CHP unit and the central boiler plant: 465,591;

(c) The total annual MMBtu's of natural gas consumed at the CHP unit alone: 440,283;

(d) The total annual MMBtu's of natural gas consumed at the central boiler plant alone: 25,308;

(e) Total increase in MMBtu's of natural gas consumed, compared to natural gas consumption prior to the CHP project being built: 301,675 (equal to 465,591.0 MMBtu from part (b) above minus 163,916.5 MMBtu gas consumption prior to the CHP project being built, rounded to nearest MMBtu);

(f) Total annual increase in MMBtu's assumed in the CIAC calculation for purposes of measuring incremental revenue from the CHP project: 301,675 from part (e) above. Please refer to the Company's response to data request Division 10-10.

Division 10-13

Request:

It appears that BQ Energy signed and certified an application labeled as the "Final" report version (dated April 11, 2018 and signed on May 4, 2018) representing that the electricity savings would be 28,924,606 kWh from the CHP project. (see pages 1098 & 1103 of Attachment DIV 4-1) Given this certification, why has the Company used an estimate of 36,155,757 kWh of electricity savings in performing the BCR calculations instead of the certified savings figure?

Response:

The Narragansett Electric Company d/b/a National Grid's (the Company) tracking system generated the referenced documents automatically. This tracking system is intended to track and manage the 80% substantial completion/20% commissioning savings claim split that is part of projects such as the Navy CHP project. The automatic document generation process incorrectly reduced the total amount of electricity savings for the project by 20% because the system currently is set up to reduce the forecasted total amount of electricity savings. The Company is in the process of correcting this system error.

The total estimated savings claim of 36,155,757 kWh/year did not change and continued to be reflected on the Minimum Requirements Document, which is the Company's record document for post inspection and commissioning purposes.

Division 10-14

Request:

Please provide the following information that corresponds to the electricity savings from the CHP project of 28,924,606 kWh that was certified in the energy efficiency application dated 4-11-18 and signed and certified by BQ Energy on May 4, 20-18, labeled as the "Final" report version (see pages 1098 & 1103 of Attachment DIV 4-1):

(a) Total annual hours of operation of the CHP unit;
(b) Total annual MMBtu's of natural gas consumed at the CHP unit;
(c) The split of winter on-peak kWh and winter off-peak kwh;
(d) Total gross kWh of electricity that will be produced by the CHP unit;
(e) Total annual net kWh of electricity that will be produced by the CHP unit (net of parasitic load).

Response:

Please see The Narragansett Electric Company d/b/a National Grid's response to data request Division 10-13 for a description of the system error that resulted in the certification reflecting the incorrect 28,924,606 kWh in electricity savings in the energy efficiency application dated 4-11-18 and signed and certified by BQ Energy on May 4, 2018, labeled as the "Final" report version. Because of the system error, the information in items (a) – (e) above that corresponds to the 4-11-18 energy efficiency application and the May 4, 2018 "Final" report is the same as the information that generated the correct amount of energy savings.

The information is as follows:

(a) Total annual hours of operation of the CHP unit: 4,532;

(b) Total annual MMBtu's of natural gas consumed at the CHP unit: 440,283 MMBtu/year (gas turbine generator + duct burner);

(c) The split of winter on-peak kWh and winter off-peak kWh: winter, on peak: 17,193,413; kWh/year (net generation); winter, off-peak: 18,962,345 kWh/year (net generation);

(d) Total gross kWh of electricity that will be produced by the CHP unit: 37,120,919 kWh/year;

(e) Total annual net kWh of electricity that will be produced by the CHP unit (net of parasitic load): 36,155,757 kWh/year.

Prepared by or under the supervision of: Mark DiPetrillo

Division 10-15

Request:

The project requirements attached to the offer letter of April 18 contains an estimate of the increased MMBTU gas consumption from the CHP unit in the minimum requirements attachment to the letter (in paragraph 9), indicating it was calculated as "fuel fired for cogen minus boiler fuel saved". This calculated estimate indicates that the total of new gas consumption is 300,000 MMBTU's. (See page 1402 of Attachment DIV 4-1).

(a) Please show how this 300,000 MMBtu estimate was calculated (including the figures used for "fuel fired for cogen" and the "boiler fuel saved").

(b) Please also explain and breakdown the fuel split of the "boiler offset of 165,600 MMBTUs" identified in paragraph 9(d).

(c) Please provide the estimates used for the calculation of 300,000 MMBtu's of increased gas usage, including the same type of information requested in 10-1 above and monthly assumptions requested in 10-2 above.

Response:

(a) The 300,000 MMBtu/year incremental gas use estimate shown in the Minimum Requirements Document (MRD) is the additional gas consumption expected because of the CHP system. To calculate this amount, The Narragansett Electric Company d/b/a National Grid (the Company) adjusted the 2015 modeled year gas consumption to 2017 values as described in the Company's response to data request Division 10-1 part (m), which shows 163,917 MMBtu/year of baseline gas consumption. The Company then subtracted 163,917 MMBtu/year from the January 2018 value of 463,957 MMBtu/year as set forth in the Company's response to data request Division 10-6 part (b). That calculation yielded 300,040 MMBtu/year, which the Company rounded down to 300,000 MMBtu/year.

(b) The boiler fuel offset is the historic fossil fuel consumption for steam production less the post-CHP boiler fuel consumption to produce steam. The 2015 modeled year energy use estimate yielded total boiler fuel consumption of 205,572 MMBtu/year, while the post-CHP boiler consumption totaled 39,971 MMBtu/year, the difference of which is 165,601 MMBtu/year. At the time of the April 18, 2018 MRD, the 39,971 MMBtu/year of post-CHP fuel use breakdown was estimated to be 80% gas/20% oil, with an oil breakdown of 80% #4 and 20% #2 as described in the Company's response to data request

Division 10-1 part (m). Therefore, at that time, the 39,971 MMBtu/year was broken down as: gas: 31,781 MMBtu/year, #4 oil: 6,480 MMBtu/year, and #2 oil: 1,620 MMBtu/year. Please see the Company's response to data request Division 10-6 part (d) and part (f) for the progression of these values between January 2018 and August 2018.

(c) The 300,000 MMBtu/year of incremental gas use of the January 2018 calculations breaks down into the monthly values shown on page 1 of Attachment DIV 10-15. The 300,000 MMBtu/year of incremental gas use in January 2018 became 301,675 MMBtu/year in the August 2018 revised calculations, resulting in the monthly values shown on page 2 of Attachment DIV 10-15.

January 2018 Calculated Values

	Pre-CHP Project Estimate			Post-CHP Project Estimate						
	2015 Total Boiler fuel use (MMBTU)	2015 Boiler Oil use (MMBTU)	2015 Boiler Gas use (MMBTU)	Post Project Boiler Oil use (MMBTU)	Post Project Boiler Gas use (MMBTU)	Post Project CHP Gas use (MMBTU)	Post Project Total Gas Use (MMBTU)	Monthly incremental gas use (MMBTU)	Sum of Hours Counter for Turbine	Sum of Gross Turbine Output (kWh)	Sum of Net Turbine Output (kWh)
Jan	41,166	8,342	32,824	2,739	10,779	60,625	71,404	38,580	599	5,119,754	4,992,188
Feb	42,499	8,612	33,887	1,983	7,802	69,950	77,752	43,864	672	5,828,452	5,685,339
Mar	37,711	7,641	30,069	2,276	8,957	59,399	68,356	38,286	599	5,033,747	4,906,180
Apr	24,130	4,890	19,241	27	108	66,324	66,432	47,191	720	5,792,126	5,638,790
May	3,680	746	2,935	0	0	19,281	19,281	16,347	216	1,680,459	1,634,458
Jun	-	-	-	-	-	0	-	-	-	-	-
Jul	-	-	-	-	-	0	-	-	-	-	-
Aug	-	-	-	-	-	0	-	-	-	-	-
Sep	-	-	-	-	-	0	-	-	-	-	-
Oct	8,423	1,707	6,716	60	237	36,554	36,790	30,074	407	3,191,020	3,104,343
Nov	22,558	4,571	17,987	966	3,801	52,110	55,911	37,924	575	4,554,469	4,432,013
Dec	25,405	5,148	20,257	48	189	67,842	68,031	47,774	744	5,920,892	5,762,445
Totals	205,572	41,656	163,917	8,099	31,871	432,085	463,957	300,040	4,532	37,120,919	36,155,757
	(a+b)	(a)	(b)	(c)	(d)	(e)	(d+e)	(d+e) - (b)			
	Oil + Gas	Oil	Gas	Oil	Gas	Gas	Gas	Gas			

August 2018 Calculated Values

	Pre-CHP Project Estimate			Post-CHP Project Estimate							
	2015 Total Boiler fuel use (MMBTU)	2015 Boiler Oil use (MMBTU)	2015 Boiler Gas use (MMBTU)	Post Project Boiler Oil use (MMBTU)	Post Project Boiler Gas use (MMBTU)	Post Project CHP Gas use (MMBTU)	Post Project Total Gas Use (MMBTU)	Monthly incremental gas use (MMBTU)	Sum of Hours Counter for Turbine	Sum of Gross Turbine Output (kWh)	Sum of Net Turbine Output (kWh)
Jan	41,166	8,342	32,824	4,959	8,559	61,748	70,308	37,484	599	5,119,754	4,992,188
Feb	42,499	8,612	33,887	3,589	6,195	71,227	77,422	43,535	672	5,828,452	5,685,339
Mar	37,711	7,641	30,069	4,120	7,112	60,506	67,618	37,549	599	5,033,747	4,906,180
Apr	24,130	4,890	19,241	50	86	67,606	67,692	48,451	720	5,792,126	5,638,790
May	3,680	746	2,935	0	0	19,656	19,656	16,721	216	1,680,459	1,634,458
Jun	-	-	-	-	-	0	-	-	-	-	-
Jul	-	-	-	-	-	0	-	-	-	-	-
Aug	-	-	-	-	-	0	-	-	-	-	-
Sep	-	-	-	-	-	0	-	-	-	-	-
Oct	8,423	1,707	6,716	109	188	37,263	37,451	30,735	407	3,191,020	3,104,343
Nov	22,558	4,571	17,987	1,749	3,018	53,121	56,139	38,152	575	4,554,469	4,432,013
Dec	25,405	5,148	20,257	87	150	69,155	69,305	49,048	744	5,920,892	5,762,445
Totals	205,572	41,656	163,917	14,662	25,308	440,283	465,591	301,675	4,532	37,120,919	36,155,757
Calculation labels	(a+b)	(a)	(b)	(c)	(d)	(e)	(d+e)	(d+e) - (b)			
Fuel	Oil + Gas	Oil	Gas	Oil	Gas	Gas	Gas	Gas	n/a	Electricity	Electricity

Also shown in Data Request response:

Annual	10-1 (f)	10-1 (d)	10-1 (c)	10-1 (b)	10-1 (e)	10-1 (a)	10-1 (h)	10-1 (i)
Monthly	10-2 (f)	10-2 (d)	10-2 (c)	10-2 (b)		10-2 (a)	10-2 (h)	10-2 (i)

Division 10-16

Request:

On page 1308 of Attachment DIV 4-1, there appears to be a note from the Navy's or BQ Energy's engineer, commenting on paragraph 9 of the minimum requirements data contained in the incentive offer letter of January 29. The comment in the box states:

> "NKE would like to review these numbers with NGRID. As they modified the CHP model with their own assumptions to model these."

Please describe the modifications to which the note is referring and explain the outcome of any discussions that may later have occurred regarding the modeling assumptions that established the minimum requirements contained in paragraph 9 of the final incentive offer letter.

Response:

Please see page 1669 of the public version of Attachment DIV 4-1, which is an e-mail describing the modifications The Narragansett Electric Company d/b/a National Grid (the Company) engineers made to the Efficiency by Design energy model during the Company's review process. The Company has also provided a copy of that email as Attachment DIV 10-16.

The Company, the Navy, and BQ Energy, LLC (BQ) did not make any changes as a result of any subsequent discussions regarding the modeling assumptions that established the minimum requirements contained in paragraph 9 of the final incentive offer letter. Rather, the Navy and BQ accepted the Company's modifications.

From: Sevier, Mark
Sent: Friday, August 3, 2018 10:30 AM
To: 'Greg Hester'; naveenk@nkengineers.com; Ferris, Gerald Jr
Subject: RE: EXT || Re: Revised Navy XL file

Hi Greg –

Thanks for taking a look at the revised model. Here is a list of items we modified internally as part of the peer review process:

Modified the CHP exhaust to steam efficiency to 97%; I don't specifically remember who made this recommendation, but it amounts to an added safety factor.
Modified CHP system start and stop dates slightly as part of the discussion about system efficiency and how the customer intended to operate the system.
Increased the outages to 3 – 6 day periods, based on ~90% 'up-time' seen with our other CHP projects.
Modified the back-up boiler minimum firing rate based on a conversation with the Navy's Bob Mulhern.
Modified the back-up boiler OA temperature based on the peer reviewer's recommendation.
Modified the fuel mix based on 2016-17 circumstances; as I mentioned, I have since learned that the fuel mix calculation method did not properly take into account the interruptible service circumstance.

I don't recall changing the heat rate safety factor; it is 3% in the "Newport CHP model 1-5-18.xlsx" that I originally got; that said, if you feel that 5% is a more realistic value, we can update that assumption as part of this revision.

Feel free to give me a call to discuss other items if that helps accelerate your review.

Thanks,
Mark
781-907-2182 o
781-696-9486 c

From: Greg Hester [mailto:greg.hester@ebdengineering.com]
Sent: Thursday, August 02, 2018 10:02 PM
To: Sevier, Mark; naveenk@nkengineers.com; Ferris, Gerald Jr
Subject: EXT || Re: Revised Navy XL file

Good evening,

I was able to download the model. Thank you Jed. I will try and take a look tomorrow in detail. I looked very quickly and it appears that a number of items had been adjusted from the last time Mark and I went back and forth on the model. One major item that I noticed was the outdoor temperature at which it is assumed that boiler #4 would be operated at a minimum fire rate. It appears that the temperature in model that was sent is not 30 degrees F and that the minimum load has also been increased to 13,000 lb/hr.

I think the process that I am going to go through the check NGrid's numbers is to perform the calculations myself and check the impact and then compare them with your numbers.

I will be in touch once I have had more time to review.

Mark, is there a list somewhere that you kept regarding other adjustments you made to the model for your final BCR calculations? It also looks like the heat rate safety factor was reduced to 3% from 5% and that the hours between the NGrid model and mine are slightly different. My current model used 4,508 hours and the NGrid model is using an extra day (4,532 hours). Not a big deal but it caught my eye.

Thank you.

Regards,

Gregory S. Hester, PE LEED AP

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From: "Sevier, Mark" <Mark.Sevier@nationalgrid.com>
Date: Thursday, August 2, 2018 at 6:45 PM
To: Greg Hester <greg.hester@ebdengineering.com>
Cc: "Ferris, Gerald Jr" <Gerald.Ferris@nationalgrid.com>
Subject: Revised Navy XL file

Hi Greg –

Thanks for speaking with me today about interruptible boiler gas supply revisions to the Navy CHP modeling file we worked on back in January. I asked Jed to send you the revised file, as I don't have easy access to send such large files.

On the "Hourly model" tab, I added columns DA & DB to split out the daily back-up boiler fuel use into gas and oil based on a curtailment temperature in cell DB2. I then used the sums shown in DA8766 & DB8766 on the 'BCR Summary 7-17-17' tab cells C70 and C68 respectively to adjust the fuel mix savings estimate, which resulted in the savings shown in yellow highlight on the BCR summary tab. Please review these adjustments, and let me know if you find other areas elsewhere in the spreadsheet where changes should be made to account for changing the back-up boilers to temperature dependent curtailment.

After I asked Jed to send you the file, I learned that the interruptible gas curtailment temperature at the customer's site is expected to be 25F / 40 HDDs as opposed to the 30F / 35 HDDs in the file I sent. Revising the curtailment temperature to 25F results in the following net gas and oil amounts on the BCR summary tab:

Increase in Natural Gas Usage (Therms) Post Project	-2,934,772
Fuel Oil Savings (MMBTU)	26,993

Thanks,
Mark
781-907-2182

Division 10-17

Request:

There is an email exchange occurring on August 2 and 3, 2018 between the Company and an engineer who appears to be representing BQ Energy, discussing the modeling assumptions for MMBTU usage (and the split between oil and gas) before and after the CHP project goes into service. (See pages 1721 through 1727 of Attachment DIV 4-1). On page 1721, a statement appears to be made by the BQ Energy engineer, stating: "As noted previously, our original model was based 2015 data (62% gas, 38% oil). We understand that NGrid adjusted the numbers for future years for their modeling purposes."

(a) Please provide the adjustment figures used by the Company, show how the adjustment was made, and explain why the adjustments were made by the Company to the oil and gas split assumptions for purposes of the BCR screening.

(b) The same email exchange has a statement from the BQ Energy engineer on page 1724: "NGrid Pre Project Split Between Gas and Fuel Oil Usage for Boilers – 163,917 MMBTU Gas (80%), 41,656 MMBTU Oil (20%) – Not sure where these numbers come from?" Please explain how the Company arrived at this projected split between gas and oil.

Response:

(a) Please see The Narragansett Electric Company d/b/a National Grid's (the Company) responses to data requests Division 10-1 part (m) and Division 10-4 for discussions of fuel proportion calculations.

(b) As described in the Company's response to data request Division 10-1 part (m), the Company adjusted the gas/oil fuel usage used for the savings calculation from the 2015 modeled year to the more recent 2017 fuel utilization. Applying the 80% gas/20% oil proportioning to the estimated 205,572 MMBtu/year of total 2015 energy consumption at the Navy's central plant resulted in 163,917 MMBtu/year of gas and 41,656 MMBtu/year of oil.

Division 10-18

Request:

Referring to the response to Division 2-8, relating to the calculation of the efficiency of the CHP unit,

(a) Please provide the estimated annual hours of production assumed in the calculation of the efficiency of the CHP unit when the Company concluded that the efficiency would be approximately 58%, as stated in the response to Division 2-8.

(b) Is the estimate of 430,359 MMBTU of total fuel consumption for the CHP unit used in the calculation consistent with the total MMBTU assumption used in the BCR calculations provided in response to Division 1-3 and corrected Division 1-3? If not, please explain why not.

(c) Please also explain the extent to which the efficiency would be affected if the number of hours of operation increase above 4,500 hours.

(d) If the consumption estimates contained in the response to Division 2-8 that calculated a unit efficiency of 58% is different than the consumption estimates contained in the response to Division 10-1 above, please re-run the efficiency calculation using the numbers provided in response to Division 10-1 and provide the results in the same form as provided in Division 2-8.

Response:

(a) The estimated hours of CHP operation associated with the conclusion that the efficiency would be approximately 58% are 4,532 hours/year.

(b) The estimate of 430,359 MMBtu/year of total fuel consumption for the CHP unit used in the calculation in The Narragansett Electric Company d/b/a National Grid's (the Company) response to data request Division 2-8 is consistent with the total MMBTU assumption used in the BCR calculations provided in Company's responses to data requests Division 1-3 and corrected Division 1-3.

Division 10-18, page 2

(c) Increasing the operational hours beyond 4,500 hours/year could have either a positive or negative effect on the efficiency of the CHP system, depending on the coincident steam needs of the Navy's steam distribution system. If the Navy's steam distribution system requires an increased number of hours of steam consumption relative to the typical weather year, both the efficiency of the CHP system, and kWh production will rise. If the CHP runs additional hours without additional steam needs, the efficiency of the CHP system will drop, while the kWh production will rise.

(d) The Company recalculated the CHP system efficiency on the energy model revisions in early August, 2018. That efficiency calculation used the estimates provided in the Company's response to data request Division 10-1. The efficiency estimate remained at 58%. Please see Attachment DIV 10-18 for a copy of the results of this efficiency calculation in the same format as provided in the Company's response to data request Division 2-8.

Navy CHP Monthly Energy & Efficiency Summary

	Delivered Electricity (MWh)	Delivered Electricity (MMBTU)	Delivered Steam (MMBTU)	Fuel Usage (MMBTU)	Electrical Efficiency	Thermal Efficiency	Monthly Overall CHP Efficiency
Jan	4,992	17,033	20,014	58,981	28.9%	33.9%	62.8%
Feb	5,685	19,398	22,806	67,040	28.9%	34.0%	63.0%
Mar	4,906	16,740	19,404	58,102	28.8%	33.4%	62.2%
Apr	5,639	19,240	19,385	67,302	28.6%	28.8%	57.4%
May	1,634	5,577	3,018	19,656	28.4%	15.4%	43.7%
Jun	-	-	-	0			
Jul	-	-	-	0			
Aug	-	-	-	0			
Sep	-	-	-	0			
Oct	3,104	10,592	6,663	37,263	28.4%	17.9%	46.3%
Nov	4,432	15,122	14,548	53,078	28.5%	27.4%	55.9%
Dec	5,762	19,661	20,429	68,937	28.5%	29.6%	58.2%
Yearly Total	36,156	123,363	126,267	430,359			

Delivered Electricity + Steam MMBTU/yr	249,630
Fuel consumption MMBTU/yr	430,359

58.0% **CHP yearly operating efficiency**

Division 10-19

Request:

The minimum requirements documents attached to the offer letter of April 12 estimates 4,500 hours of operation, not counting forced outages of the unit – in paragraph 5(a). (see page 1081 of Attachment DIV 4-1)

(a) Is there any consequence for the customer if the hours of operation are below 4,500 hours? Please explain the significance of this apparently being listed as a minimum number of hours of operation;
(b) Is the 4,500 hours a minimum requirement or the expected annual number of hours of operation under normal weather conditions?
(c) If the 4,500 hours is a minimum number of hours required, what is the expected number of hours of operation under normal weather conditions?
(d) If the CHP plant operation materially exceeds 4,500 hours of operation, what type of impact would a material increase in hours have on the BCR, if a significantly higher number of hours was used in the calculation instead of the minimum?
(e) Are there any consequences for the customer if any other minimum requirements specified in the minimum requirements document are not achieved? If yes, please identify and explain.
(f) Does the minimum requirements document now need to be amended to reflect updated estimates? If yes, please show how it will be amended. If not, please explain why not.

Response:

(a) There is no consequence to the customer solely because the hours of operation are below 4,500 hours/year. If reduced hours of operation result in reducing the efficiency of the CHP unit below 55%, then the customer could face a consequence, including loss of incentive. Additionally, The Narragansett Electric Company d/b/a National Grid (the Company) will adjust the savings and non-electric benefits it claims, if warranted. The Company's CHP program manager works with customers and CHP vendors throughout the project development and implementation process to maximize the benefits delivered by CHP systems that receive incentives, including making sure the overall efficiency does not drop below the minimum required efficiency of 55% shown in Minimum Requirements Document (MRD) Milestone 1, section 9 (h).

The intent of putting the 4,500 hours/year of operation into the MRD is to set expectations that the CHP system will run for the majority of the winter season. The Company expects that the Navy will operate the CHP system as the "first run, large

boiler," while limiting the rejection of useful thermal energy. The Company included the estimated annual operating time of 4,500 hours/year in the MRD based on a typical weather year within the energy model calculations. As described in the Company's response to data request Division 10-18 part (c), the reason for a change to the number of actual annual operating hours (either increased hours or decreased hours of operation) has a material effect on the impacts to the customer and the distribution system.

(b) The 4,500 hours/year is the expected annual operating hours under normal weather conditions.

(c) Please see the Company's response to part (b) above.

(d) As described with respect to efficiency in the Company's response to data request Division 10-18 part (c), benefits associated with changes in the operating hours are a function of the thermal load of the Navy's steam distribution system during the winter season. If the annual CHP operating hours increase due to increased steam distribution needs during a colder than normal winter, then the BCR will improve. If the CHP operates for a greater number of hours during a normal weather winter or a warmer winter, then the BCR will decrease. The Company calculates the BCR based on average conditions as the best prediction of the performance of Energy Efficiency (EE) measures over their expected measure life.

(e) The MRD describes characteristics of the energy model as a guide to ensure a successful project. The Company is committed to advising the customer through the installation process to ensure a successful financial project for all customers and the individual customer. There are, however, a few items that are of consequence, in particular, the state minimum requirement that annual system efficiency is at least 55%. If this 55% metric is not met, the Company will request that the customer and contractor bring the performance in line with that state minimum; typically, the customer and contractor have 6 months to comply. If the customer fails to meets the requirements, then the remaining incentive amount will be withheld, and the Company will enforce a clawback on any other incentive applied to the project. The MRD often is created prior to when real actual runtime characteristics are realized. The objective of the MRD is to guide the implementation team toward reaching the estimated savings goals with good faith efforts from the project team and the Company during the implementation phase of the project. The Company negotiates and suggests ways to improve the performance so that both parties meet a mutually agreed upon financial project. Some of the actual metrics in the MRD are a target instead of a minimum amount.

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(f) Based on the revised calculations, the following changes were made to the MRD:
   a. Milestone 1, section 9, part (b): Gas fuel increase changed from 300,000 MMBTUs Higher Heating Value (HHV) to **301,675 MMBTUs HHV**;
   b. Milestone 1, section 9, part (c): Oil usage reduction changed from 33,556 MMBTUs to **26,993 MMBTUs**;
   c. Milestone 1, section 9, part (f): Thermal efficiency changed from modeled at 30% HHV to **29% HHV**;
   d. Milestone 1, section 9, part (g): Plant overall efficiency changed from modeled at 59% HHV to **58% HHV**; and
   e. Milestone 2b, section 2, part (c): Plant overall efficiency changed from 59% to **58%.**

Division 10-20

Request:

It appears that the design of and the cost estimate for the gas distribution reinforcements identified in response to Division 6-3 were developed in or around July 2017, when the Company was estimating total gas consumption at 533,371 dekatherms.

(a) Does the change in load profile that occurred (after the first engineering estimate was made) affect the scope and/or cost of the system reinforcement? Please explain why or why not.

(b) Does the change in operation of the CHP unit which would prohibit the CHP unit from operating on days when the temperature is colder than a 52 HDD affect the scope and/or cost of the system reinforcement needed to assure that the distribution system will be able to safely and reliably serve the CHP unit? Please explain why or why not.

Response:

(a) The change in the annual load consumption profile that occurred after the first engineering estimate was made does not affect the scope and/or cost of the system reinforcement. The scope of the system reinforcement is based on the peak hourly consumption of the proposed CHP equipment on a design day. Operations Engineering evaluated the distribution system impact of the CHP equipment load addition for both the original peak hourly load of 126 Dth per hour and the revised peak hourly load of 141 Dth per hour. At both loads, the recommended system reinforcement involves connecting the ends of two 12-inch mains with new main so the scope and cost of the proposed reinforcement is the same due to the reinforcement providing additional distribution system capacity beyond the capacity necessary to serve the original load.

(b) The change in operation of the CHP unit, which would prohibit the CHP unit from operating on days when the temperature is colder than a 52 HDD, would allow a reduction in the required diameter of the proposed reinforcement to 6 inches. However, Operations Engineering has advised that installing a 12-inch diameter main is a more prudent investment for the long term reliability of distribution system flows and pressures, particularly because the investment is supported by incremental gas distribution revenues.

Prepared by or under the supervision of: Matthew A. Foran and Stephen A. Caliri

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Division 10-22

Request:

At what heating degree temperature does the Company typically interrupt customers taking service on the interruptible Rate 61? Please provide data from the last five years showing the dates for each interruption, and identifying the HDD temperature at which such interruptions were called.

Response:

The Narragansett Electric Company d/b/a National Grid typically interrupts customers taking service on the interruptible Rate 61 when weather conditions are expected to be 40 HDD or colder.

Please see Attachment DIV 10-22 for the data from the last five years showing the dates for each interruption and identifying the HDD temperature at which such interruptions were called.

Historical Non-Firm Customer Curtailments - Rhode Island

2013-2014	HDD	2014-2015	HDD	2015-2016	HDD	2016-2017	HDD	2017-2018	HDD	2018-2019	HDD
11/24/2013	42	1/6/2015	49	1/4/2016	47	12/15/2016	48	12/13/2017	41	11/21/2018	36
12/12/2013	44	1/7/2015	53	1/5/2016	44	12/16/2006	44	12/14/2017	45	11/22/2018	48
12/13/2013	41	1/8/2015	42	1/13/2016	42	1/6/2017	39	12/27/2017	50	11/23/2018	37
12/14/2013	39	1/9/2015	45	1/18/2016	44	1/7/2017	47	12/28/2017	56		
12/15/2013	37	1/10/2015	47	1/19/2016	42	1/8/2017	50	12/29/2017	53		
12/16/2013	45	1/13/2015	45	1/20/2016	38	1/9/2017	51	12/30/2017	50		
12/17/2013	43	1/14/2015	41	1/21/2016	39	2/2/2017	34	12/31/2017	58		
12/18/2013	36	1/15/2015	38	1/22/2016	36	2/3/2017	38	1/1/2018	56		
12/31/2013	43	1/16/2015	40	2/11/2016	49	2/4/2017	36	1/2/2018	48		
1/1/2014	40	1/25/2015	38	2/12/2016	45	2/9/2017	47	1/3/2018	41		
1/2/2014	54	1/26/2015	43	2/13/2016	62	2/10/2017	42	1/4/2018	42		
1/3/2014	59	1/27/2015	49	2/14/2016	59	2/16/2017	36	1/5/2018	56		
1/4/2014	44	1/28/2015	50			3/4/2017	48	1/6/2018	60		
1/5/2014	24	1/29/2015	37			3/15/2017	41	1/7/2018	48		
1/6/2014	33	1/30/2015	42			3/16/2017	35	1/14/2018	45		
1/7/2014	55	1/31/2015	47			3/17/2017	31	1/15/2018	44		
1/8/2014	47	2/1/2015	41					2/2/2018	48		
1/9/2014	43	2/2/2015	47					2/3/2018	37		
1/18/2014	32	2/3/2015	47								
1/21/2014	52	2/4/2015	31								
1/22/2014	55	2/5/2015	49								
1/23/2014	52	2/6/2015	46								
1/24/2014	48	2/9/2015	46								
1/25/2014	38	2/10/2015	39								
1/26/2014	40	2/11/2015	49								
1/27/2014	39	2/12/2015	45								
1/28/2014	48	2/13/2015	57								
1/29/2014	48	2/14/2015	42								
2/6/2014	43	2/15/2015	57								
2/7/2014	42	2/16/2015	51								
2/8/2014	39	2/17/2015	47								
2/9/2014	39	2/18/2015	42								
2/10/2014	45	2/19/2015	52								
2/11/2014	48	2/20/2015	57								
2/12/2014	41	2/23/2015	55								
2/16/2014	41	2/24/2015	47								
2/25/2014	42	2/25/2015	38								
2/26/2014	45	2/26/2015	48								
2/27/2014	46	2/27/2015	45								
2/28/2014	48	2/28/2015	47								
3/1/2014	32	3/5/2015	47								
3/2/2014	34	3/6/2015	48								
3/3/2014	47										
3/4/2014	39										
3/5/2014	42										
3/6/2014	43										
3/7/2014*	31										
3/13/2014	47										
3/17/2014	40										

HDD value as provided by Company's weather service provider for Providence RI.

* Additional Navy interruption due to lower than normal AGT pressure feeding Aquidneck Island. Navy was called between 6:30AM-7AM and asked to cease taking service as soon as possible. They were able to do so within 30 minutes.

Division 10-23

Request:

Does the Company keep records relating to its temperature forecasting accuracy? If so, please provide information for the last five years identifying the days during the winter peak season when the Company's prior day forecast was incorrect because the actual temperature for a forecasted day ended up being much colder than forecasted.

Response:

The Narragansett Electric Company d/b/a National Grid (the Company) does keep records relating to the temperature forecasting accuracy of its weather service provider (i.e. archived historical weather forecast emails and historical weather data). The Company, however, neither keeps track of forecasting accuracy nor prepares accuracy reports because, in most instances, unexpected changes in the weather forecast for the current Gas Day (defined as the 24-hour period beginning at 10:00 a.m.) do not generate short-notice curtailment requests and such reports would not be impactful to the Company's gas dispatch operations. Unless system integrity is being impacted or the change in weather forecast is significant (*i.e.* > 3 HDD), the Company likely will not take any action because of colder-than-forecast weather conditions. For reference, in accordance with the terms and conditions of non-firm service, the Company attempts to provide non-firm customers three working days' notice of a curtailment except in emergency situations.

To assess forecasting accuracy is a manual process requiring the comparison of weather forecast information embedded within multiple emails to the actual weather data. For purposes of responding to this data request, please see Attachment DIV 10-23 for a listing of all dates in the last five years where either the day-ahead forecast HDD or the actual HDD were greater than or equal to 52 HDD. There are two dates on which the actual HDD exceeded the day-ahead forecast by more than 3 HDD, and there is one date on which the actual HDD fell below the day-ahead forecast by more than 3 HDD. The Company chose the 52 HDD threshold to prepare this data because it is relevant to the firm service level proposed for the Navy's CHP equipment and because it would be overly burdensome to review the data for every day for the last five years.

Dates with Day-Ahead Forecast HDD or Actual HDD >=52 HDD

Date	"Day Ahead" Forecast HDD	"Current Day" Forecast HDD	Actual HDD
1/23/2013	52	52	55
1/2/2014	48	49	54
1/3/2014	60	62	59
1/7/2014	50	54	55
1/21/2014	50	48	52
1/22/2014	56	56	55
1/23/2014	54	53	52
1/7/2015	51	53	53
2/13/2015	59	59	57
2/15/2015	57	57	57
2/16/2015	57	55	51
2/19/2015	53	53	52
2/20/2015	55	55	57
2/23/2015	58	58	55
2/13/2016	62	61	62
2/14/2016	59	59	59
12/28/2017	56	55	56
12/29/2017	50	51	53
12/31/2017	57	57	58
1/1/2018	55	56	56
1/5/2018	58	57	56
1/6/2018	63	61	60

= Actual HDD exceeded the <=52 HDD forecast by more than 3 HDD

= Actual HDD fell below the >52 HDD forecast by more than 3 HDD

Division 10-24

Request:

Please provide the following data from the last five years:

(a) Dates when the temperature was a 40 HDD or colder, stating the coldest temperature reached for each day;
(b) Dates when the temperature was colder than 52 HDD, stating the coldest temperature reached for each day.

Response:

Please see Attachment DIV 10-24 for Gas Days when the temperature was 40 HDD or colder and Gas Days when the temperature was colder than 52 HDD, including the coldest temperature reached for each Gas Day. A Gas Day is the 24-hour period beginning at 10:00 AM.

2013

DATE	WEATHER	> 52 HDD	>= 40 HDD	MIN TEMP
01/01/13	40		40	16
01/02/13	45		45	9
01/03/13	41		41	18
01/21/13	40		40	20
01/22/13	49		49	9
01/23/13	55	55	55	5
01/24/13	51		51	10
01/25/13	46		46	12
01/26/13	47		47	11
01/27/13	40		40	20
02/01/13	40		40	19
02/04/13	40		40	22
02/09/13	46		46	13
02/10/13	40		40	15
02/17/13	45		45	15
11/24/13	42		42	18
12/12/13	44		44	15
12/13/13	41		41	14
12/16/13	45		45	10
12/17/13	43		43	17
12/25/13	42		42	20
12/31/13	43		43	18

DATE	WEATHER	> 52 HDD	>= 40 HDD	MIN TEMP
01/01/14	40		40	21
01/02/14	54	54	54	3
01/03/14	59	59	59	-2
01/04/14	44		44	15
01/07/14	55	55	55	6
01/08/14	47		47	15
01/09/14	43		43	15
01/21/14	52		52	8
01/22/14	55	55	55	3
01/23/14	52		52	7
01/24/14	48		48	11
01/26/14	40		40	17
01/28/14	48		48	14
01/29/14	48		48	9
01/30/14	41		41	17
02/06/14	43		43	14
02/07/14	42		42	14
02/10/14	45		45	13
02/11/14	48		48	7
02/12/14	41		41	20
02/16/14	41		41	14
02/17/14	44		44	12
02/25/14	42		42	17
02/26/14	45		45	10
02/27/14	46		46	9
02/28/14	48		48	8
03/03/14	47		47	10
03/05/14	42		42	13
03/06/14	43		43	13
03/13/14	47		47	13
03/17/14	40		40	18
12/30/14	41		41	17

DATE	WEATHER	> 52 HDD	>= 40 HDD	MIN TEMP
01/06/15	49		49	12
01/07/15	53	53	53	0
01/08/15	42		42	11
01/09/15	45		45	12
01/10/15	47		47	11
01/13/15	45		45	15
01/14/15	41		41	21
01/16/15	40		40	11
01/26/15	43		43	16
01/27/15	49		49	13
01/28/15	50		50	5
01/30/15	42		42	12
01/31/15	47		47	12
02/01/15	41		41	17
02/02/15	47		47	6
02/03/15	47		47	10
02/05/15	49		49	2
02/06/15	46		46	14
02/08/15	41		41	16
02/09/15	46		46	17
02/11/15	49		49	11
02/12/15	45		45	6
02/13/15	57	57	57	0
02/14/15	42		42	16
02/15/15	57	57	57	-3
02/16/15	51		51	10
02/17/15	47		47	13
02/18/15	42		42	16
02/19/15	52		52	2
02/20/15	57	57	57	-3
02/23/15	55	55	55	-3
02/24/15	47		47	11
02/26/15	48		48	10
02/27/15	45		45	10
02/28/15	47		47	8
03/02/15	41		41	14
03/05/15	47		47	10
03/06/15	48		48	9

DATE	WEATHER	> 52 HDD	>= 40 HDD	MIN TEMP
01/04/16	47		47	9
01/05/16	44		44	14
01/13/16	42		42	20
01/18/16	44		44	18
01/19/16	42		42	21
01/23/16	40		40	19
02/08/16	44		44	20
02/11/16	49		49	7
02/12/16	45		45	18
02/13/16	62	62	62	-9
02/14/16	59	59	59	0
12/10/16	42		42	15
12/15/16	48		48	8
12/16/16	44		44	16
12/19/16	42		42	17

DATE	WEATHER	> 52 HDD	>= 40 HDD	MIN TEMP
02/09/17	47		47	9
02/10/17	42		42	18
02/11/17	41		41	20
03/04/17	48		48	11
03/05/17	40		40	16
03/10/17	41		41	14
03/11/17	48		48	11
03/12/17	45		45	13
03/15/17	41		41	21
12/13/17	41		41	21
12/14/17	45		45	11
12/15/17	42		42	19
12/26/17	45		45	13
12/27/17	50		50	8
12/28/17	56	56	56	5
12/29/17	53	53	53	8
12/30/17	50		50	11
12/31/17	58	58	58	2

DATE	WEATHER	> 52 HDD	>= 40 HDD	MIN TEMP
01/01/18	56	56	56	3
01/02/18	48		48	12
01/03/18	41		41	18
01/04/18	42		42	12
01/05/18	56	56	56	4
01/06/18	60	60	60	-3
01/07/18	48		48	7
01/14/18	45		45	15
01/15/18	44		44	17
01/25/18	40		40	19
01/30/18	40		40	15
02/02/18	48		48	10
11/22/18	48		48	14
12/08/18	40		40	20

Division 10-26

Request:

Please explain the extent to which the addition of the gas demand from the CHP unit will restrict the Company's ability to serve other new firm customers with unrestricted firm service when the temperature drops close to or below 52 HDD, without the Company needing to add new pipeline capacity infrastructure to Aquidneck Island.

Response:

The addition of gas demand from the CHP unit will not restrict the The Narragansett Electric Company d/b/a National Grid's (the Company) ability to serve other new firm customers with unrestricted firm service when the temperature drops close to or below 52 HDD, without the Company needing to add new distribution system pipeline capacity infrastructure to Aquidneck Island. The distribution system reinforcement discussed in the Company's response to data request Division 2-3, which is required to add the CHP unit demand to the distribution system, will improve the Company's ability to serve other new firm customers with unrestricted firm service when the temperature drops close to or below 52 HDD. The reinforcement, comprised of 3,000 feet of 12-inch plastic main, connects two dead-end 99 psig mains to provide additional distribution system capacity beyond the capacity necessary to serve the additional demand from the CHP unit, thus delaying the need for the Company to add new distribution system pipeline infrastructure to Aquidneck Island.

The addition of gas demand from the CHP unit is not expected to restrict the Company's ability to serve other new firm customers with unrestricted firm service when the temperature drops close to or below 52 HDD, without the Company needing to add new upstream pipeline capacity infrastructure to Aquidneck Island, based on the most recent gas peak day load growth forecast for Aquidneck Island. As discussed in the Company's response to data request Division 10-27, and based on the Company's most recent gas peak day load growth forecast for Aquidneck Island, the 52 HDD limit results in a distribution system load that does not exceed the 22,089 dth maximum daily quantity (MDQ) pipeline contract at the Portsmouth take station through the 2027-28 winter. Therefore, at temperatures close to 52 HDD, the Company has the ability to serve other new firm customers with unrestricted firm service as forecasted based on the Company's most recent gas peak day load growth forecast for Aquidneck Island. At temperatures below 52 HDD, the CHP unit is expected to cease operation and would not impact the Company's ability to serve other new firm customers with unrestricted firm service. As explained in the Company's response to data request Division 9-2, if the CHP project was operating with firm gas service on a day when the temperature exceeded the 52 HDD threshold, and the Company experienced a significant enough drop in pipeline supply pressure at the

Division 10-26, page 2

Portsmouth take station to place existing customers on Aquidneck Island at risk of service interruption, then the Company would take measures to send a crew out to the site to physically shut a valve on the gas service supplying the Navy's CHP equipment.

An increase in the peak day load growth forecast for Aquidneck Island in future years would accelerate the need for additional upstream pipeline capacity to Aquidneck Island. A decrease in the peak day load growth forecast for Aquidneck Island in future years would delay the need for additional upstream pipeline capacity to Aquidneck Island.

Division 10-27

Request:

Referring to the gas capacity analysis provided in response to Division 2-4 in Attachment 2-4. Please provide an explanation of the analysis and how to interpret it.

Response:

Attachment DIV 2-4 provides The Narragansett Electric Company d/b/a National Grid's (the Company) most recent gas peak day load growth forecast for the area of Aquidneck Island, adjusted for temperatures warmer than peak day conditions and at the range where the 52 heating degree day (HDD) limit was determined. The first table in the attachment provides the adjusted forecast without the Navy CHP project load. The second table in the attachment provides the adjusted forecast with the Navy CHP project load of 2,520 dth added. A 52 HDD condition is the coldest temperature at which the Navy CHP load can be added to the distribution system up through the 2027-28 winter without exceeding the maximum daily quantity (MDQ) of 22,089 dth at the Portsmouth take station. The forecast volumes in both tables reflect total firm load, including Capacity Exempt (CE) customer load as well as 51 % of the Firm Transportation customers (FT-1) for which the Company does not plan capacity.

Division 10-28

Request:

Please confirm whether, as a practical matter, there is any interstate pipeline capacity into Aquidneck Island which is currently available for purchase. Please provide details as to amount available and estimated cost.

Response:

There is no additional interstate pipeline capacity with delivery to Aquidneck Island currently available for purchase.

Division 10-29

Request:

Using the monthly consumption profile provided in response to Division 10-1, please provide an annual gas distribution and supply bill estimate for the CHP unit based on current rates (hypothetically assuming usage for the period from October 1, 2018 through September 30, 2019), separating delivery from commodity and showing how the bill estimate is calculated. Please perform this bill estimate twice, using Rate 34 and Rate 24 in each case. To the extent there are any rate component(s) subject to change, please provide a reasonable estimate for such component(s) in the calculations. Please show the bill estimate for each month for the 12-month period, as well as annual total.

Response:

Please see Confidential Attachment DIV 10-29 for an annual gas distribution and supply bill estimate for the CHP unit based on current rates on both Rate 34 and Rate 24. Please note that the Commercial and Industrial Energy Efficiency factor for January 2019 through September 2019 has not yet been approved by the Public Utilities Commission, but it is proposed as $0.0420 per therm.

Attachment DIV 10-29

REDACTED

Prepared by or under the supervision of: Matthew A. Foran

Division 10-31

Request:

Pages 1006 through 1191 of the Confidential version of Attachment DIV 4-1 are all blank white pages. Were there documents inadvertently left out of production at these pages or was there some other type of discovery production error that resulted in these pages being blank?

Response:

There were no documents inadvertently left out of the production. The blank pages located at pages 1006 through 1191 of the Confidential version of Attachment DIV 4-1 are the result of imaging the Microsoft Excel spreadsheet, entitled "Navy_powerplant_6459108006 Jan_01_2017 to Jan_01_2018.xlsx," which is an attachment to the email located at Page 781. The blank pages are a part of that spreadsheet. The Excel spreadsheet attachment is comprised of pages 783 through 1192 of the Confidential version of Attachment DIV 4-1.